N244

MEMORANDUM

DATE: February 13, 1986

TO: Dick Whiting / Nevada Dept. of Minerals

FROM: Dick Benoit / Oxbow

SUBJ: Six Well Test Carbonate Scale Logging

CC: File

Please find enclosed two copies of a report on the results of the carbonate scale logging in the Dixie Valley production wells during the six well flow test. Also enclosed are two copies each of the original Schlumberger logs for this study. Please note that the Schlumberger logs include borehole televiewer logs for wells 73-7 and 45-33 which have collapsed and swedged casing.

CALIPER LOGGING OF CALCITE SCALE IN DIXIE VALLEY WELLBORES

Dick Benoit

February 13, 1987

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INTRODUCTION

During production, the Dixie Valley wells produce calcium carbonate scale as a result of patial flash in the wellbores. The scaling characteristics such as volume, depth, length, and thickness of scale depend upon several variables including chemistry of the fluid, amount of fluid produced, size of the wellbore, depth of the flash point, and changes in depth of the flash point during production. Given these variables it would be a major undertaking to prepare a detailed physical and chemical model of the scaling rates and associated wellbore restrictions for each production well at Dixie Valley. There is simply not enough data yet available for such a study. Therefore a relatively simple analysis is presented to give an estimate of the carbonate scaling rates in the Dixie Valley production wells and of the amounts of fluid and time that can pass before it becomes necessary to clean out the wellbores.

In all wells except 27-33 the amount of scale was determined with Schlumberger's multifinger caliper log, a state of the art caliper tool. In well 27-33 the scale was logged with a 3 arm bowspring type, single trace tool.

The original logging plan was to log three or four of the more productive wells after the six well test. This was changed to include all six wells once the two weakest wells, 32-18 and 65-18, were selected as candidate injection wells. These two wells were logged so preparations could be made to get them in shape for injection testing in 1987. In addition, Schlumberger offered a free experimental borehole televiewer log on one well and a very low price of 300 dollars on a second well. We selected the wells 45-33 and 73-7 which have damaged casing so they could be further evaluated. By the time Schlumberger had set up on these wells it was very cost effective to also run the multifinger caliper tool.

Wells 27-33 and 84-7, while not flowed as part of the six well test, were caliper logged during the first half of 1986. Wells 65-18, 74-7, 73-7, 76-7, and 45-33 were logged in November 1986 after the six well test was completed and the wellbores had conductively cooled to below 300 deg. F. The multifinger caliper tool will not function in temperatures above 350 deg. F.

Well 32-18 could not be logged because an impassable obstruction, which is interpreted to be collapsed casing, was encountered at a depth of 280' by the caliper tool.

The expected depth of scale was estimated from the probable flash points on the flowing temperature logs. In all wells except 74-7 the scale was found within the expected depth range. In well 74-7 the scale was deeper than indicated by the flowing temperature logs.

In wells 84-7 and 65-18 the bottom of the scale was located a short distance above the 9 5/8" liner hanger, which was quite fortunate because the logging tool, for unknown reasons, could not be lowered through these hangers.

Replotted scale profiles from all wells are shown on Figure 1. This allows an easy visual comparison between wells with respect to length, thickness, and general shape of the scaled interval. The relative visual scale volume estimates from Figure 1 can be misleading due to the different sizes of wellbores involved. For instance, well 74-7, with 13 3/8" casing, contains about 11,000 cubic inches of scale more than well 65-18 with 9 5/8" casing. Yet it would appear that well 65-18 contains the larger volume of scale. The discrepency results from the larger diameter casing in well 74-7 requiring a larger volume of scale to reach the same thickness as would be present in a smaller diameter casing.

The caliper logs (Figure 1) show the scale in all wells, except 74-7, to have the classic shape of a flame above a candle. Scale begins to form at the deepest flash point and rapidly increases upward in thickness to a maximum within 100' to 400'. Above this maximum the scale gradually decreases in thickness over a length of up to 1300'.

Scale and production parameters for the wells are shown on Table 1.

PRODUCTION HISTORY

Well 27-33

Well 27-33 has been caliper logged twice to determine scale buildup. However, the most recent caliper log (single trace) for well 27-33 has been reinterpreted. The reason for the reinterpretation is that the original length of the scaled interval (1950') appears excessive in light of the

Carbonate Scale Profiles
Dixie Valley Production Wells

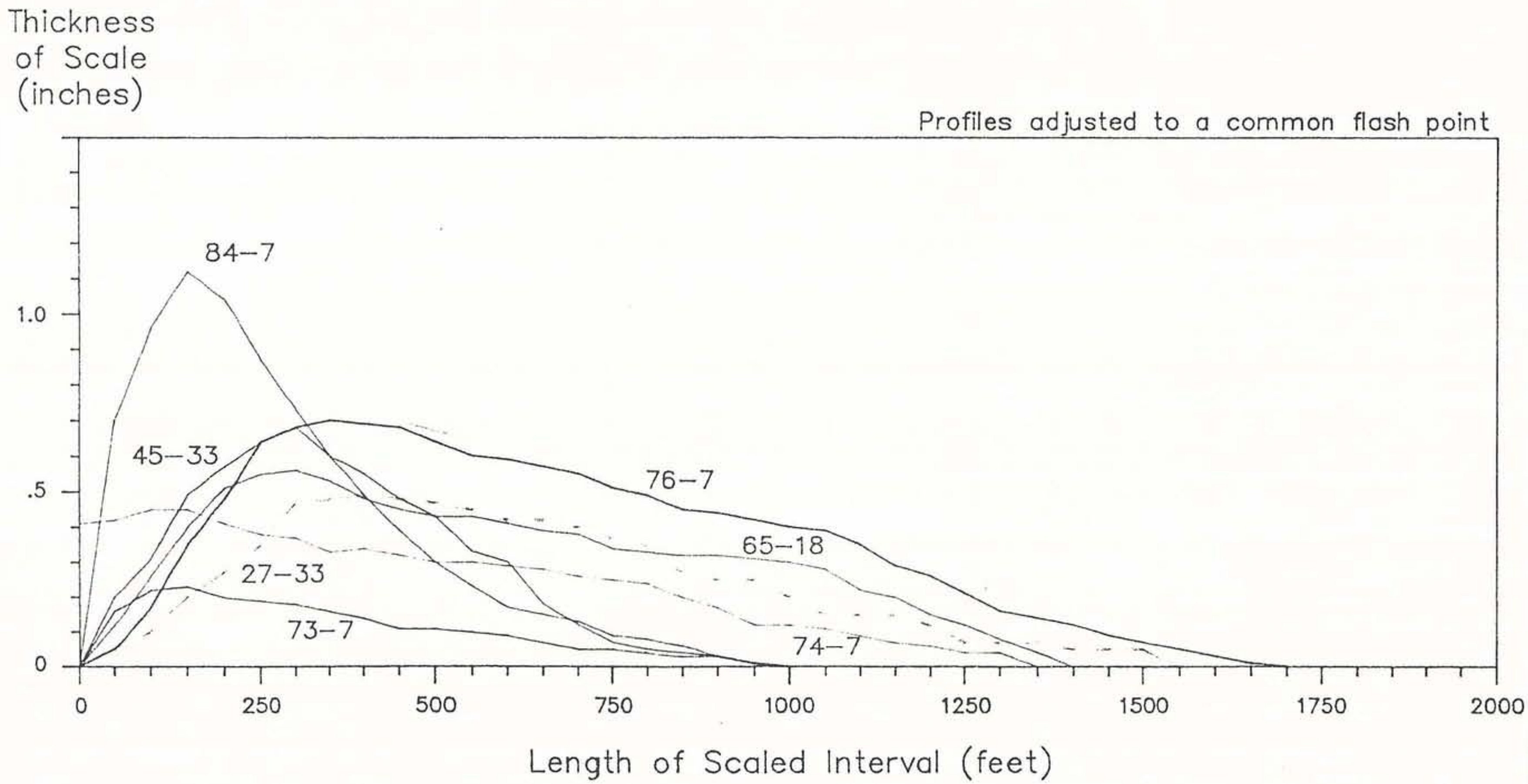

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Figure 1

TABLE 1

DIXIE VALLEY CARBONATE SCALE CALIPER LOGGING DATA

WELL	DAYS FLOWED	FLOW RATE (kph)	TOTAL FLUID PRODUCED (Thousands of Lbs)	INTERNAL DIAMETER OF CASING (Inches)	VOLUME OF SCALE (Cubic In)	MAXIMUM SCALE THICKNESS (Inches)	DEPTH TO BOTTOM OF SCALE (Feet)	DEPTH TO TOP OF SCALE (Feet)	LENGTH OF SCALE (Feet)	WELLHEAD PRESSURE (Psia)	INITIAL FLASH POINT DEPTH (Feet)	FINAL FLASH POINT DEPTH (Feet)	AVERAGE SCALING RATE (Lbs of Fluid/In 3)	PERCENT RESTRICTION
27-33	86	370	726,000	8.755	102,640	0.50	4290	2756	1534	96-92	3700	3930	7073	22
84-7	75	650	1,170,000	8.835	119,796	1.14	2366	1416	950	161-153	2457	2457	9767	45
65-18	54	786-476	737,019	8.835	140,319	0.58	2155	760	1395	115-79	1243	1998	5252	25
45-33	60	1020-852	1,260,453	8.681	104,355	0.68	1882	900	982	153-128	1393	1725	12,079	29
73-7	40	1097-1013	901,278	10.05	46,104	0.27	2631	1658	973	135-127	2408	2878	19,550	10
76-7	65	1722-1109	1,997,549	12.515	274,323	0.70	2840	1200	1640	161-111	1748	2758	7,282	21
74-7	82	1350-928	1,969,136	12.415	151,924	0.46	3251	1920	1331	175-133	2597	3470	12,961	14

more recent and more accurate multifinger caliper data from all the other wells. Shortening the length of the scaled interval also reduces the calculated volume of scale available, from 109,970 to 102,640 cubic inches. The April 1986 logging occurred after the well had flowed for 86 days at a constant flowrate of 370,000 lbs/hr. During the early 1986 flow test the well produced 726,000,000 pounds of fluid and created 102,640 cubic inches of scale for a scaling rate of one cubic inch of scale for each 7073 pounds of fluid produced.

The 27-33 profile shown on Figure 1 actually contains 122,784 cubic inches of scale, not the 102,642 cubic inches shown on Table 1. This is because scale deposited in the wellbore prior to 1985 is included on Figure 1.

Since well 27-33 was logged it has been reworked and made into a far more productive well. Prior to the rework it took a 1000 pound pressure drop for this well to flow. This explains why the bottom of the scale in well 27-33 is located over 1000' deeper than in any of the other wells. Now that the efficiency has been greatly improved it is expected future scale will form in the range of 1000' to 3000'. Consequently the scaling characteristics of well 27-33 should not apply to the well in its present condition. Since the workover, well 27-33 has only been flowed for a short rig test so no new information is available.

Well 84-7

Well 84-7 was caliper logged on May 24, 1986 after it had produced 1,170,000,000 pounds of fluid at a constant flow rate of 650,000 lbs/hr. With a maximum scale thickness of 1.14", 84-7 has the thickest scale measured at Dixie Valley as well as one of the shortest scaled intervals.

Well 65-18

Well 65-18 was caliper logged on November 14, 1986 after it had produced 737,018,902 pounds of fluid during a 24 hour rig test and during the six well test. This well has the highest scaling rate of all wells logged.

Well 45-33

Well 45-33 was caliper logged on November 13, 1986 after it had produced 1,260,452,948 pounds of fluid during the short rig test following the workover and during the six well test.

Well 73-7

Well 73-7 was caliper logged on November 13, 1986 after it had produced 901,277,788 pounds of fluid during the six well test. Well 73-7 had the least volume of scale with only 46,104 cubic inches. This could in part be a result of the swedging operation carried out during the middle of the six well test. The casing collapsed during the six well test and during the swedging operations it is very likely that some scale was knocked down the wellbore by the swedge and the drillpipe. In addition, 2600' of coiled tubing was lost in the well when it was kicked off. The tubing was removed prior to swedging and had up to 0.1" of scale which normally would have adhered to the casing. For these reasons the volume and thickness of the scale and the scaling rate in well 73-7 are best viewed as minimums.

The maximum measured scale thickness was 0.27" in a casing diameter of 10.05". Well 73-7 is the only well in Dixie Valley with 10.05" diameter production casing. Even though the scale in well 73-7 is thin it has already developed the classical shape and a length of almost 1000' (Figure 1).

Well 76-7

Well 76-7 was caliper logged on November 14, 1986 after it had produced a total of 1,997,549,309 pounds of fluid during a one hour rig test and the six well test . Well 76-7 produced the most fluid of all wells and created the most scale, 274,323 cubic inches. Well 76-7 has the longest scaled interval, measured at 1640'.

Well 74-7

Well 74-7 was caliper logged on November 14, 1986 after it had produced a total of 1,969,135,755 pounds of fluid during a one hour rig test, a two week flow test in April and May 1986, and the six well flow test. The scale formation in well 74-7 is unique in that the bottom of the scale is at the top of the 9 5/8" liner hanger but apparently entirely within the 13 3/8" casing. The scale is close to its thickest at 3251' (Figure 1). The change in wellbore diameter is close enough to the calculated flash point that it may have exerted major control on the location of scale deposit.

INTERPRETATION

The most obvious correlation expected in analyzing this data should be between the volume of fluid produced and the amount of scale created (Figure 2). As the volume of fluid produced increases the amount of scale deposited also increases as expected. However, the data do not define a narrow linear trend. In particular there is a lot of scatter between the 9 5/8" wellbores. The two 13 3/8" wellbores do not show any resemblance of a trend away from the origin. This demonstrates that factors other than wellbore size and volume of fluid produced control the quantity of scale formation.

One of the major controls on scale formation is the chemistry of the reservoir fluid, in particular the noncondensible gas content, and amounts of bicarbonate, carbonate, and calcium. As calcium is the least abundant of these components it is the most affected by scale formation. It is simple to calculate the amount of calcium removed from the fluid to produce a given amount of scale. Assuming that the scale has a density of 2.0 g/cc the amount of calcium lost to scale is shown on Table 2.

TABLE 2

CALCULATION OF PARTS/MILLION CALCIUM PRECIPITATED AS SCALE

WELL	SCALE VOLUME (inches 3)	WEIGHT OF CALCIUM (pounds)	WEIGHT OF FLUID PRODUCED (pounds x 10 6)	PPM OF CA LOST TO SCALE
27-33	102,640	2970	726	4.1
84-7	119,796	3466	1170	3.0
65-18	140,319	4060	737	5.5
45-33	104,355	3019	1260	2.4
73-7	46,104	1334	901	1.5
76-7	274,323	7937	1998	4.0
74-7	151,924	4396	1969	2.2

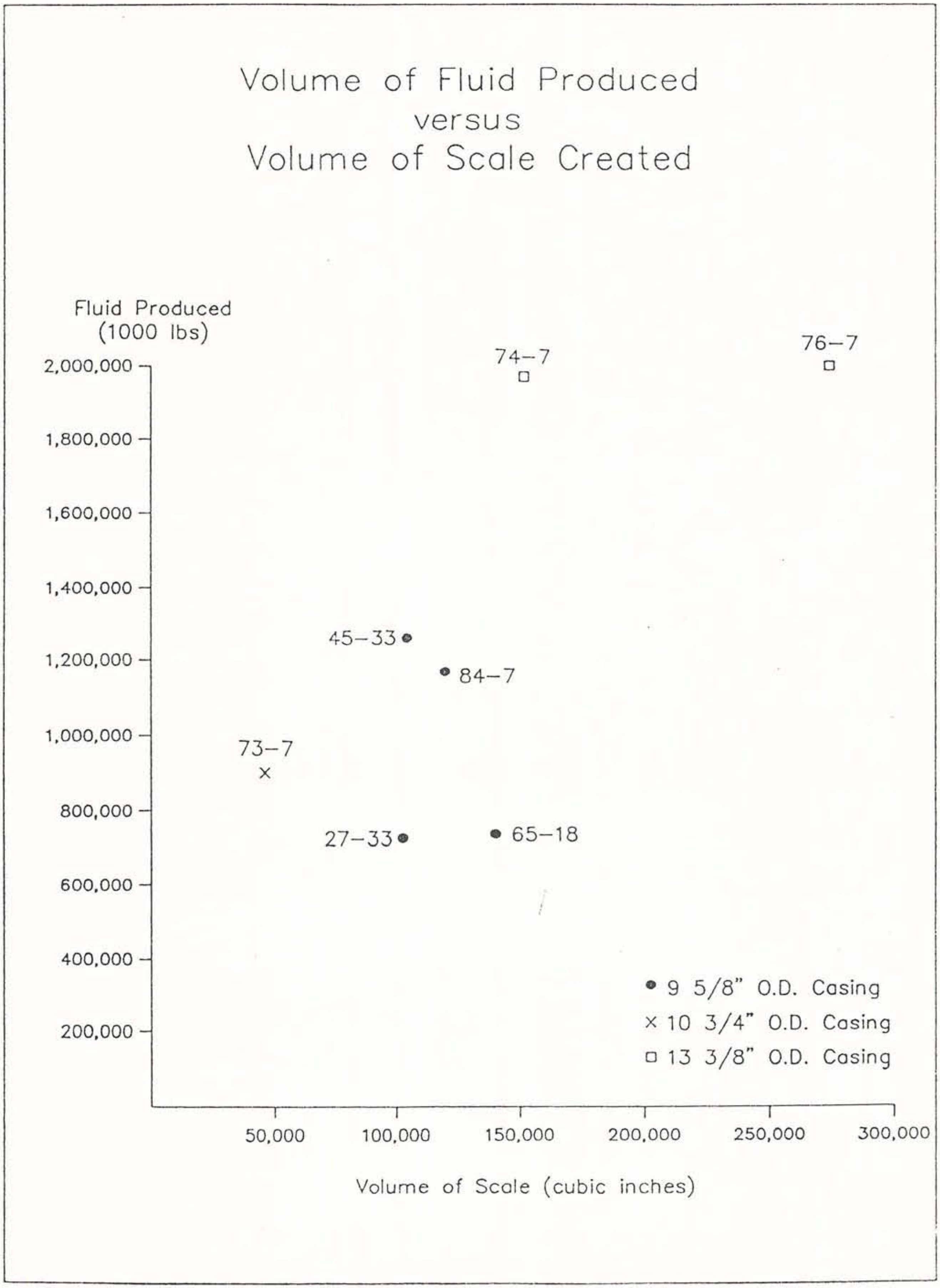

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Figure 2

The amount of calcium precipitated in the scale ranges between 2.2 and 5.5 parts per million, with the exception of well 73-7, in which the volume of scale produced is known to be more than was actually measured. In all wells except 32-18 the amount of calcium in the brine (corrected for steam loss) was slightly less than one part per million (ppm). In well 32-18 the measured calcium was 1.6 ppm. Nearly all of the available calcium was precipitated before geochemical samples could be collected at the surface. This indicates calcium is the limiting factor in scale formation. If the assumption of 2.0 g/cc for the scale density is too high then slightly less calcium would have been precipitated. This variation (between 2.2 and 5.5 ppm) is a factor of two and one half. While none of the major elements in the Dixie Valley brine show this large percentage variation between wells, some minor elements such as fluoride vary in quantity by a factor of two. As calcium is present in minor amounts in the Dixie Valley fluids it is likely that the large pre-flash variation is real.

This variation indicates that the scaling characteristics of each well can be, and probably are, quite unique and is why many of the graphs do not have well-defined curves or trends. To thoroughly understand the scale characteristics at Dixie Valley it may be necessary to repeatedly log each well as it becomes progressively scaled.

Other correlations between pounds of fluid produced and scale parameters such as length of scaled interval and maximum scale thickness are also weak (Figures 3 and 4). Comparison between length of scaled interval and maximum scale thickness and the volume of scale show generalized trends of increasing length and thickness with increasing scale volumes (Figures 5 and 6). As scaling progresses, both the length of scaled interval and maximum thickness of scale increase.

From a production viewpoint the most important scale parameter is the maximum thickness, as this is the dominant factor in reducing the flow of the well over the short term. If it is assumed that a given volume of scale will be produced by a given volume of fluid in an individual well, then the length of the scaled interval will in large part control the thickness. The length and thickness of scale should be inversely related and by increasing the length of scale a thinner scale will result. However, no distinct correlation between length and thickness can be shown (Figure 7). Figure 7 shows that the minimum scale length in the Dixie Valley wells is between 950 and 1000'.

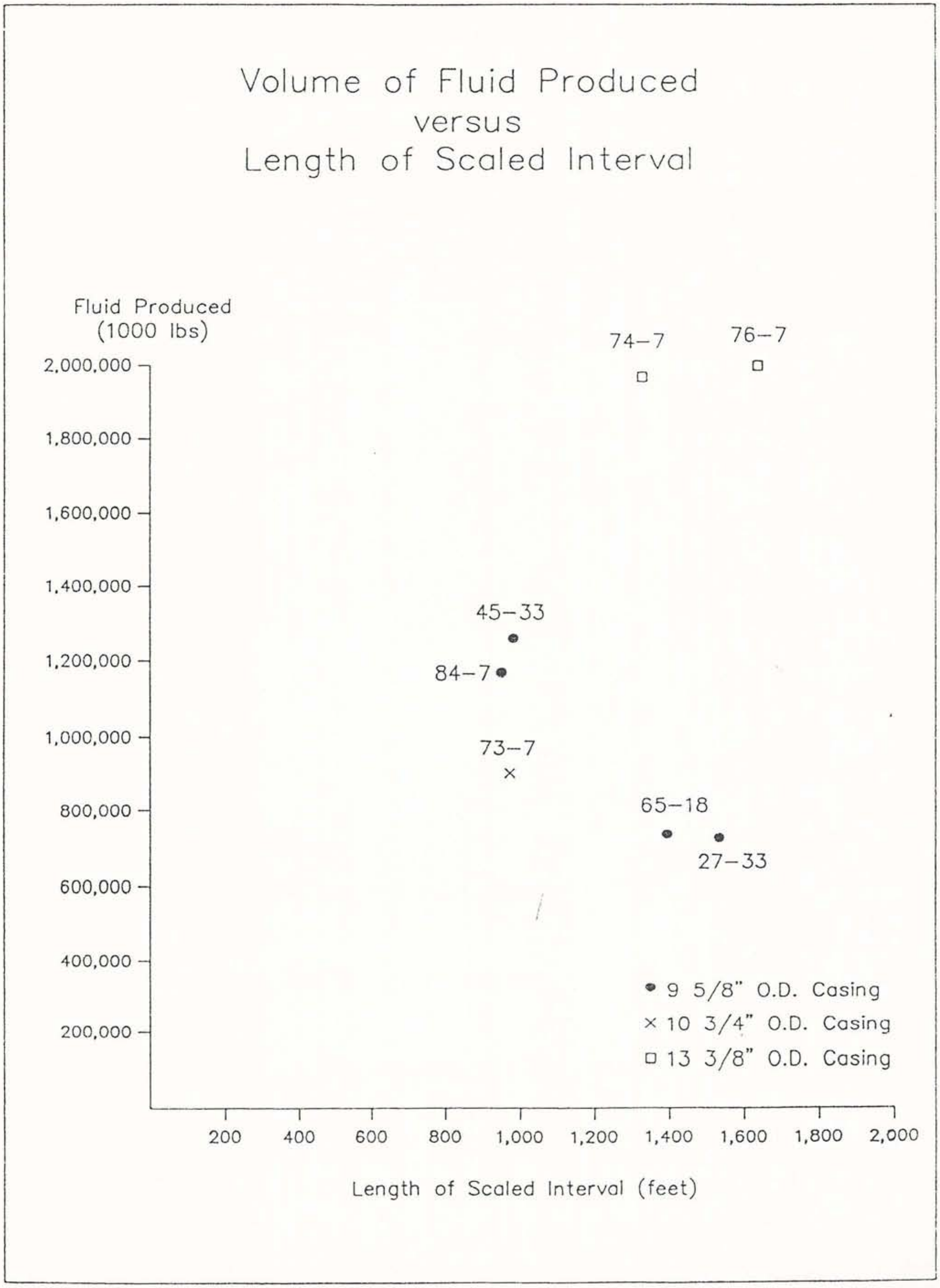

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Figure 3

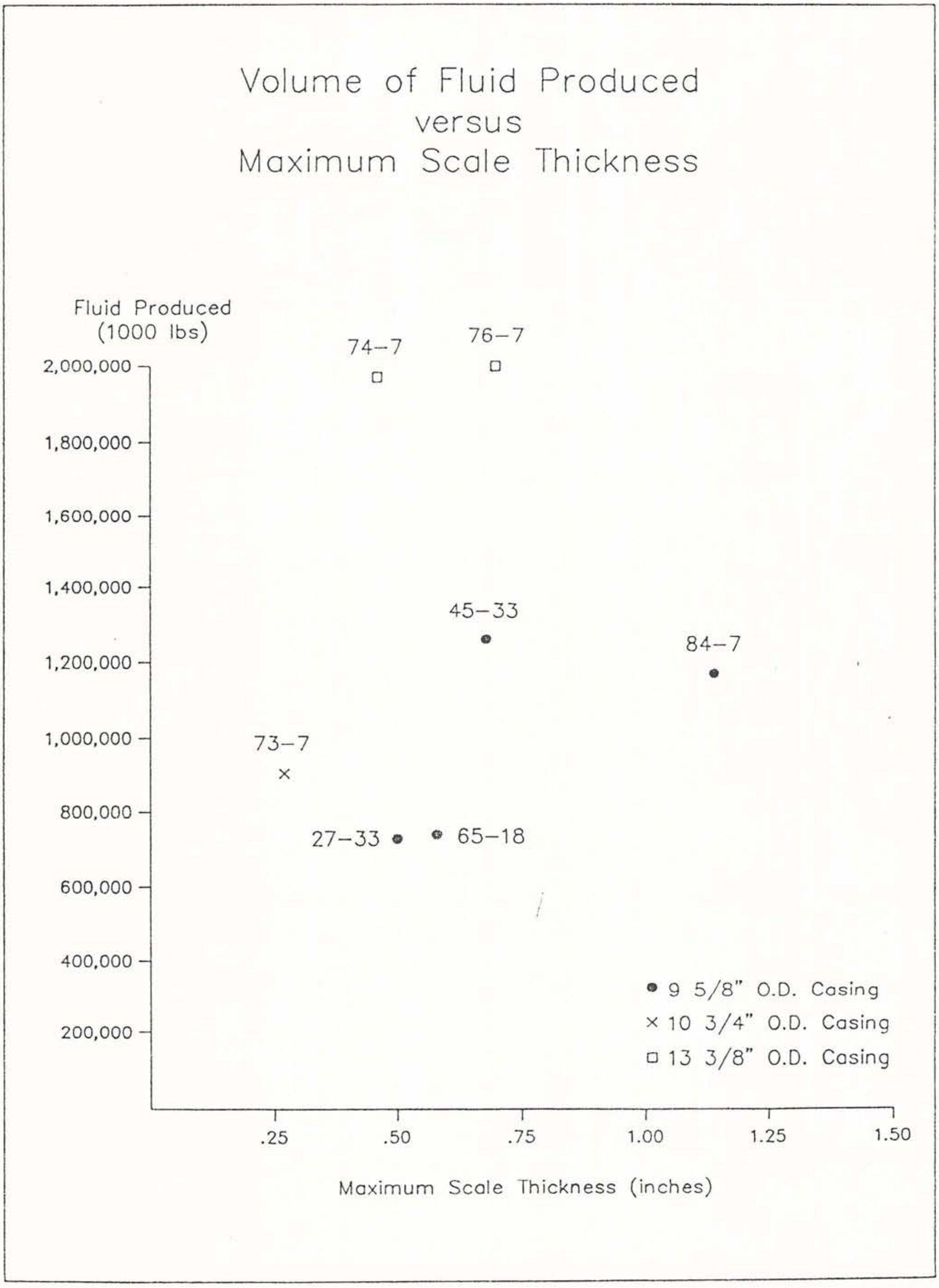

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Figure 4

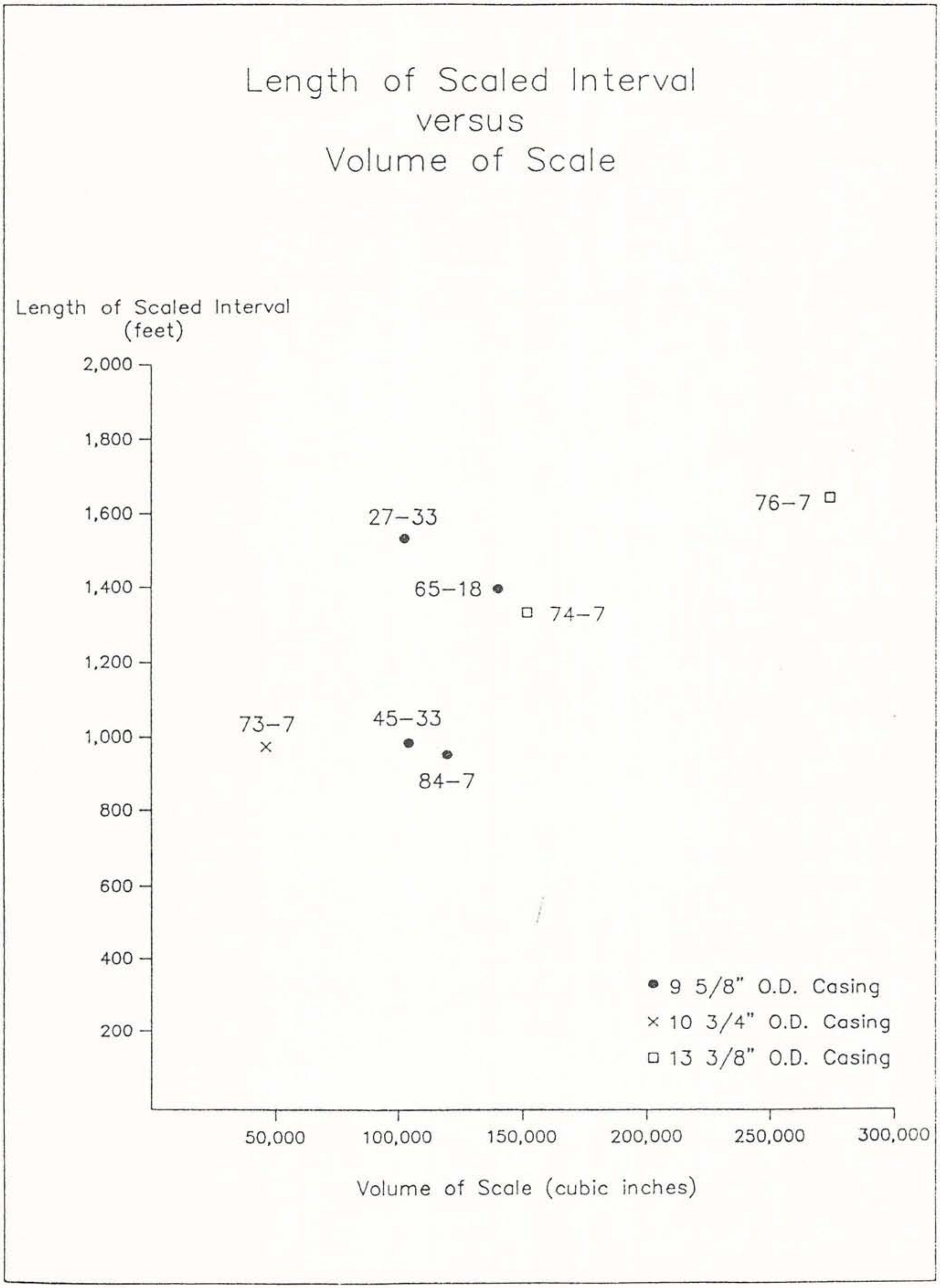

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Figure 5

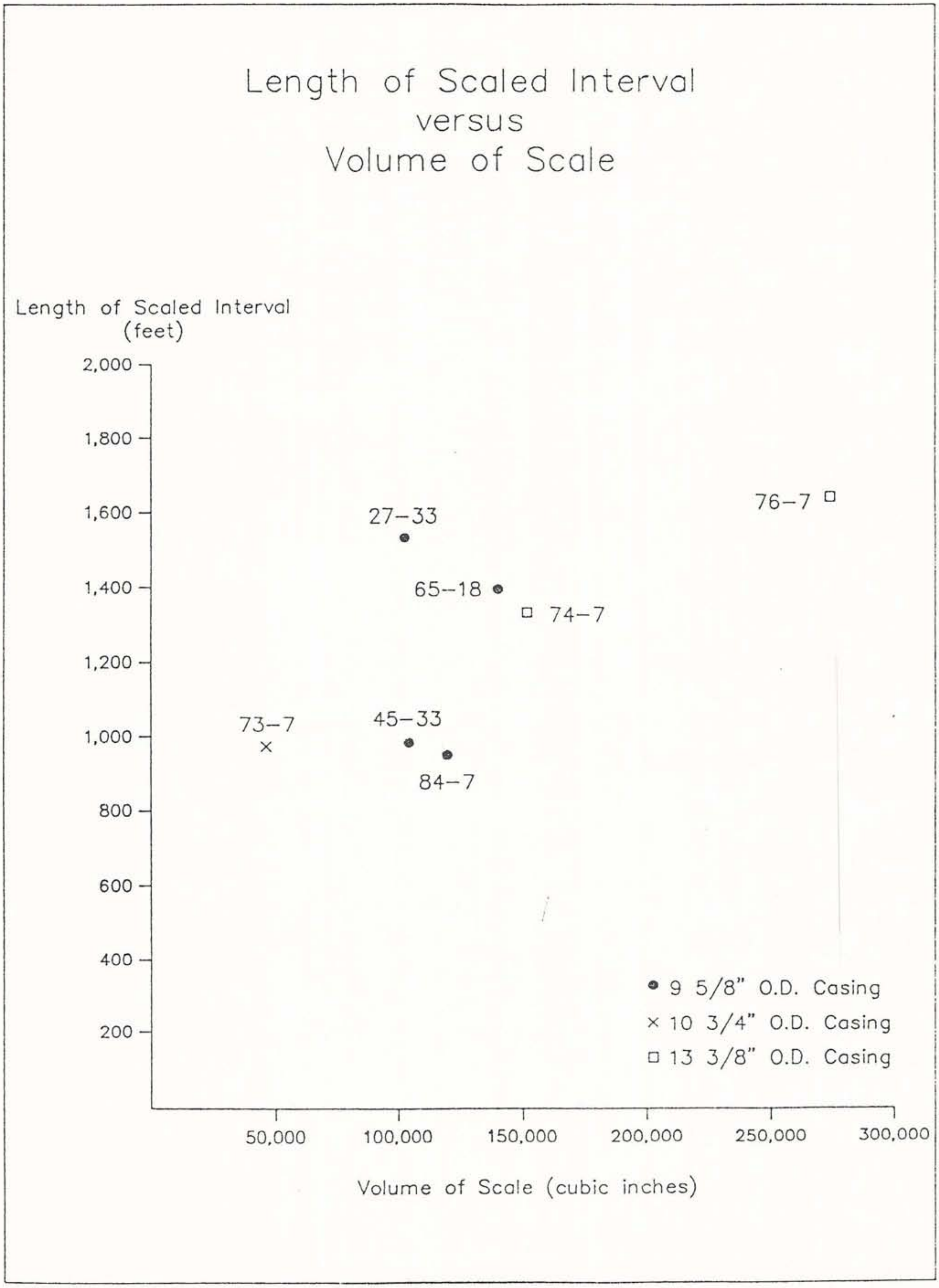

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Figure 5

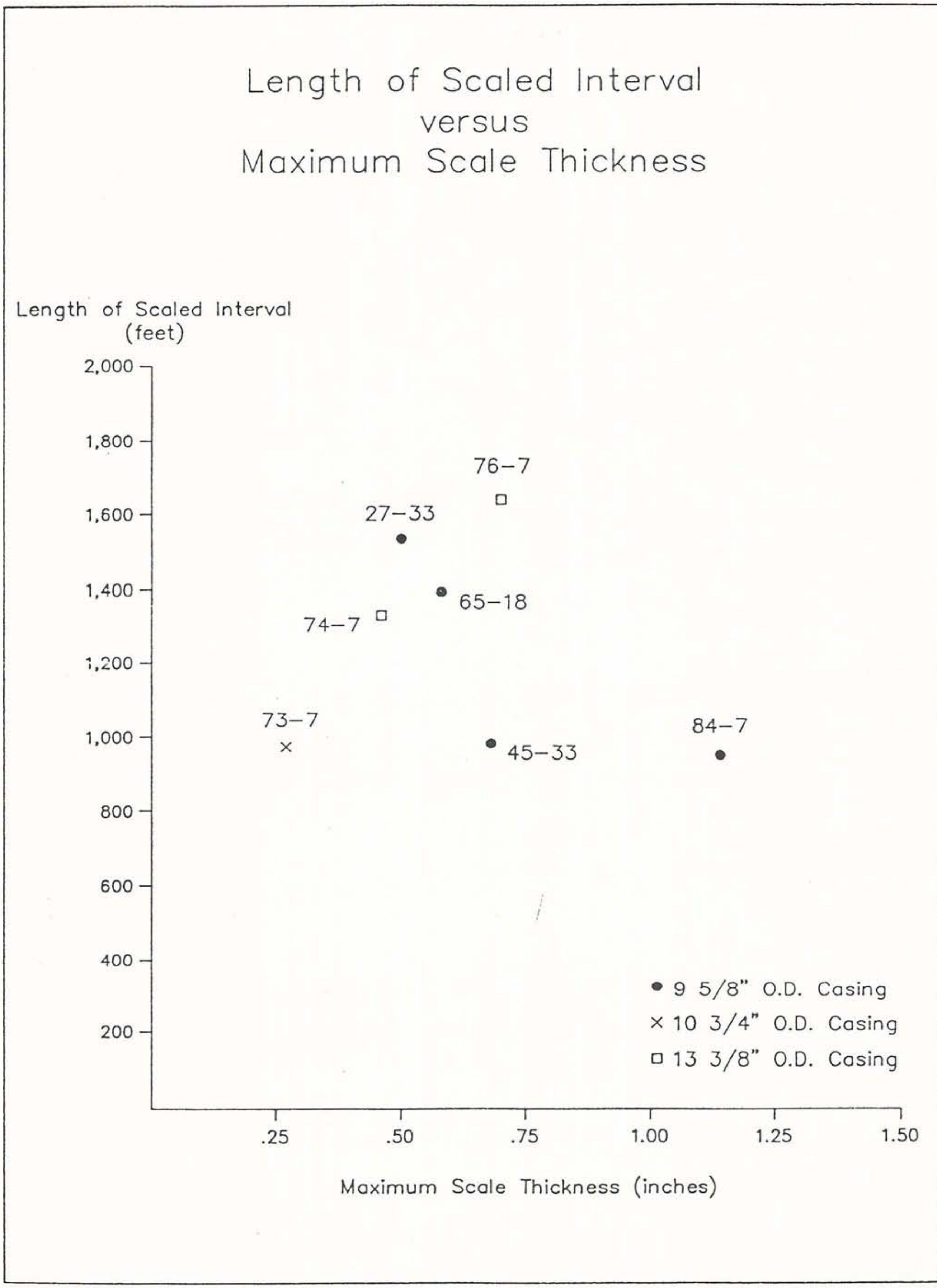
Length of Scaled Interval
versus
Maximum Scale Thickness
Length of Scaled Interval
(feet)
2,000
1,800
1,600
1,400
1,200
1,000
800
600
400
200
76-7
27-33
65-18
74-7
73-7
84-7
45-33
9 5/8" O.D. Casing
10 3/4" O.D. Casing
13 3/8" O.D. Casing
.25
.50
.75
1.00
1.25
1.50
Maximum Scale Thickness (inches)

Figure 7

This probably represent the length over which the carbon dioxide gas exsolves from the liquid phase during flashing. A change in the flash point with time should also lengthen the scaled interval.

The parameter most likely controlling the length of the scaled interval is the amount of wellhead pressure change and associated flash point depth changes. If the flash point moves up or down the wellbore during production presumably the scale length will increase and the maximum thickness will be less than if the scale built up over a shorter length. This is especially true during the time when the wellbore is clean. As the wellbore becomes progressively scaled and the wellhead pressure has declined, the ability to move the flash point by varying the wellhead pressure will diminish. Ultimately the downhole scale restriction will be the primary control over the wellhead pressure, if scaling is allowed to continue. Also in practice it will be much easier to lower the wellhead pressure as the well becomes progressively scaled than to raise the wellhead pressure as this will further depress the flow rate.

During all of the Oxbow flow testing to date, no attempt has been made to either vary or stabilize the wellhead pressures other than during the short-term productivity tests. The wells were simply flowed at the maximum possible flow rates given the surface facilities. This resulted in wellhead pressures that had highly variable decline over time. (Table 1).

Information on the calculated flash point depths is presented in Table 1. These depths were calculated with the wellbore simulation program WELF by Roger Harrison and have been corrected for noncondensible gas content. The relationship between calculated flash point depth changes between the beginning (initial) and end (final) of the flow testing intervals and the associated wellhead pressure changes is shown on Figure 8. The wells show a reasonable correlation between the two parameters as expected. A 10 pound change in wellhead pressure means the flash point has moved about 200'. Now that the relative relationship between wellhead pressure and the flash point depth has been demonstrated the wellhead pressure parameter will be used to interpret the scale length interval. This is because the wellhead pressure is a measured parameter and the scale length is not tied to a particular depth in the well.

Figure 9 shows the relationship between the change in wellhead pressure while the well was flowing and the length of scale. All of the wells except 27-33 create a relatively well-defined trend of increasing scale length with increasing amount of change in wellhead pressure.

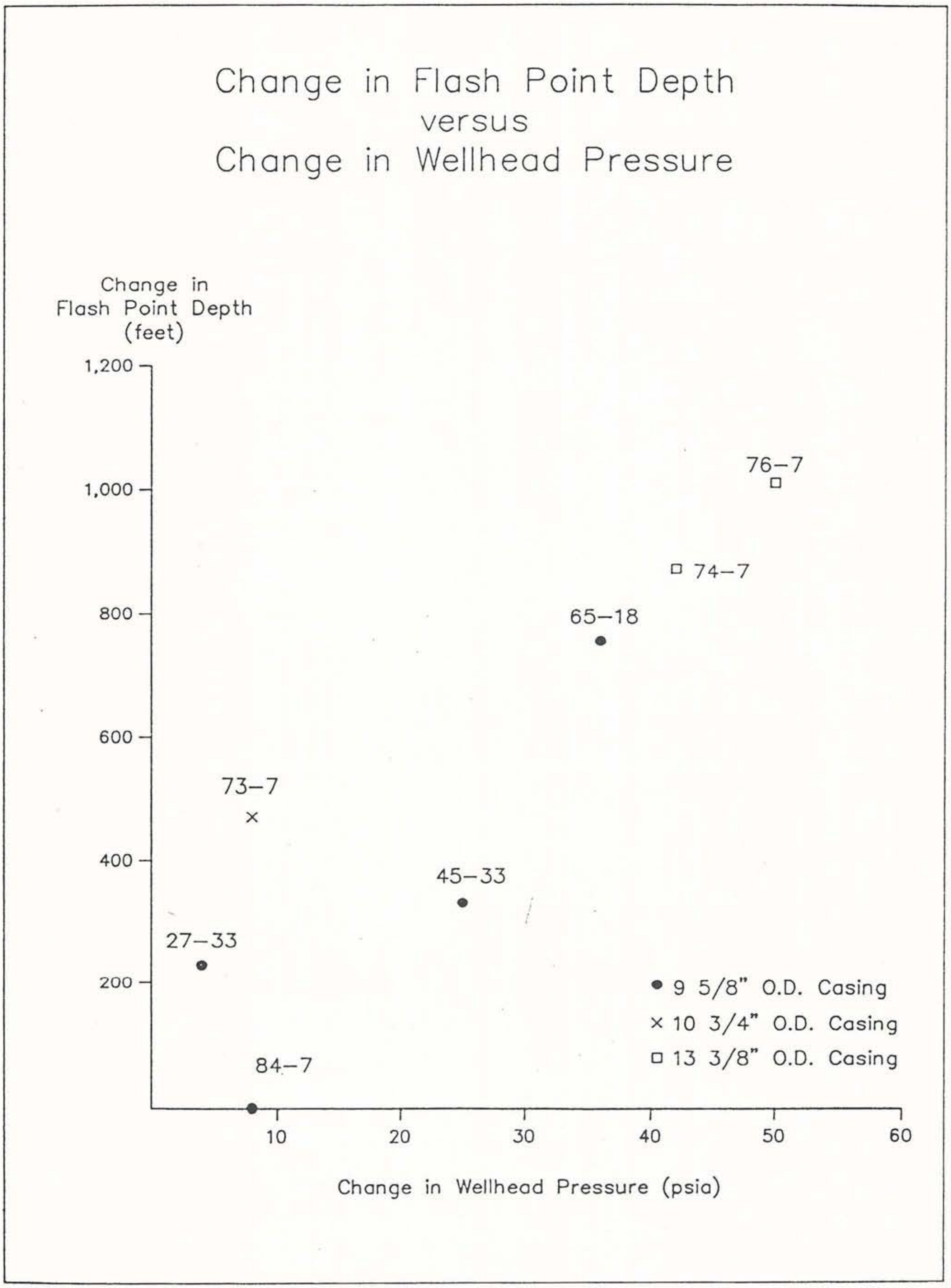

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Figure 8

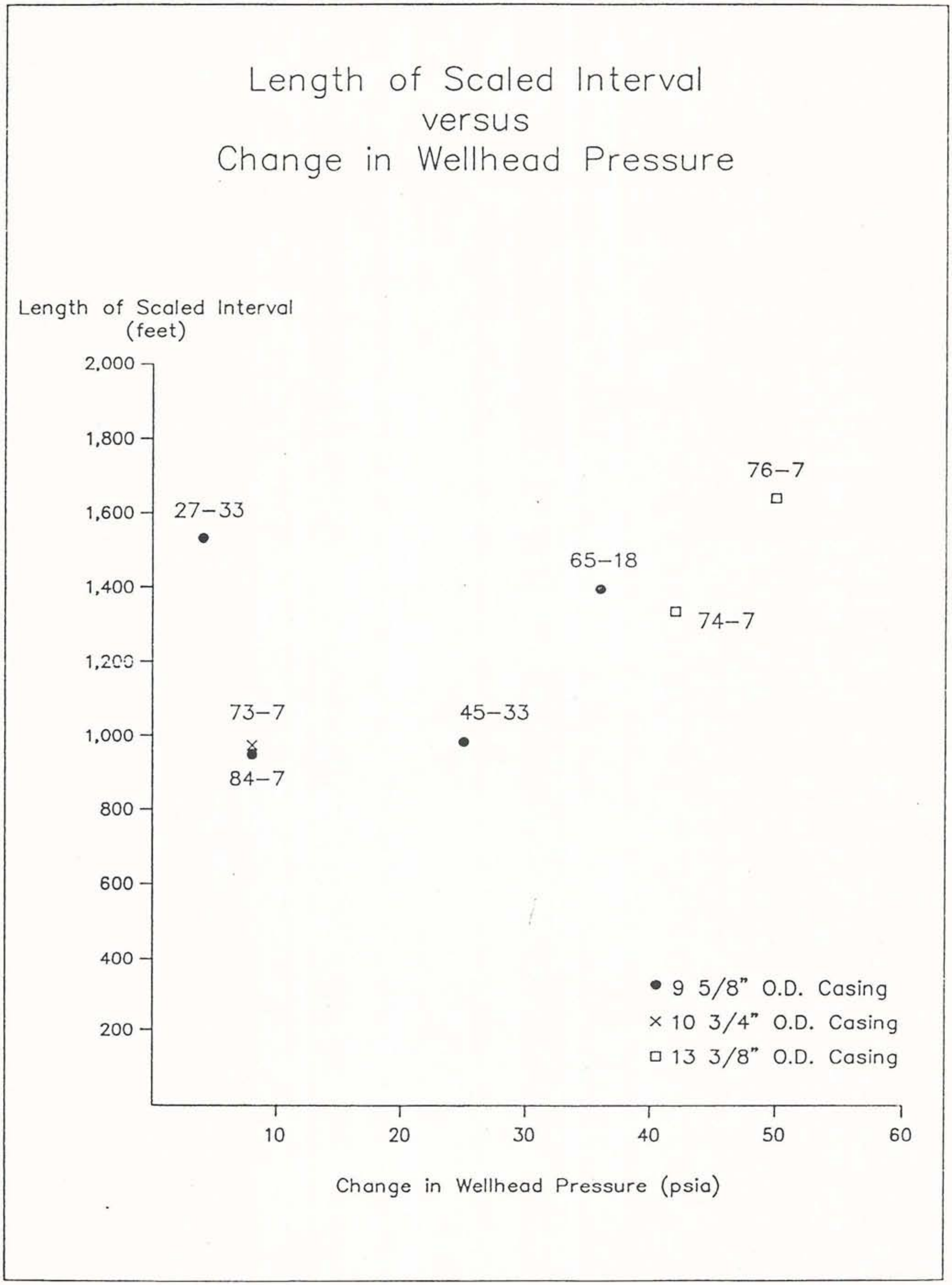

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Figure 9

Extrapolating the trend to zero change in wellhead pressure shows that the minimum expected scale length in these wells will be between about 600 and 800'. Therefore this is most likely the length over which the carbon dioxide gas exsolves from the brine during flashing.

Most of the pressure change occured early in the flow test before significant scale could have deposited. This indicates that the varying wellhead pressure during production spread out the scale over longer sections of the wellbore. This also indicates the declines in wellhead pressure and flow rate were primarily due to changes in the reservoir and not as a result of scaling. If the wellhead pressure changes had been most pronounced near the end of the test, it is likely that the length of scale would have been controlled in large part by the pressure drop resulting from the scale restriction and scaling would be a major cause of the wellhead declines.

Figure 10 shows no clear correlation between maximum scale thickness and change in wellhead pressure when all seven wells are considered and no strong correlation is expected because the volume of fluid produced is not taken into account. The maximum thickness of scale should be more dependent than the length of scale on the volume of fluid produced. However, if well 73-7 is ignored because the scale volume is known to be greater than measured, then only well 27-33 falls significantly off a trend of increasing scale thickness with decreasing wellhead pressure changes. Well 27-33 was also the only well on the graph of length of scale versus change in wellhead pressure that was off the trend.

An average scaling rate for each well is shown on Table 1. This is simply the pounds of fluid that had been produced divided by the cubic inches of scale. It is believed that this rate is not constant but increases as the well becomes progressively scaled or restricted. The scaling rates range from 5252 to 19550 pounds of fluid needed to produce one cubic inch of scale. Well 73-7 apparently has the lowest scaling rate but this is known to be incorrect. If well 73-7 is not considered, the minimum scaling rate drops to 12,961 pounds of fluid per cubic inch of scale.

Experience elsewhere in the Basin and Range province has shown that wells with 13 3/8" completions can produce at larger flow rates, up to 6 times as long as wells with 9 5/8" completions, in the same reservoir between scale cleanouts.

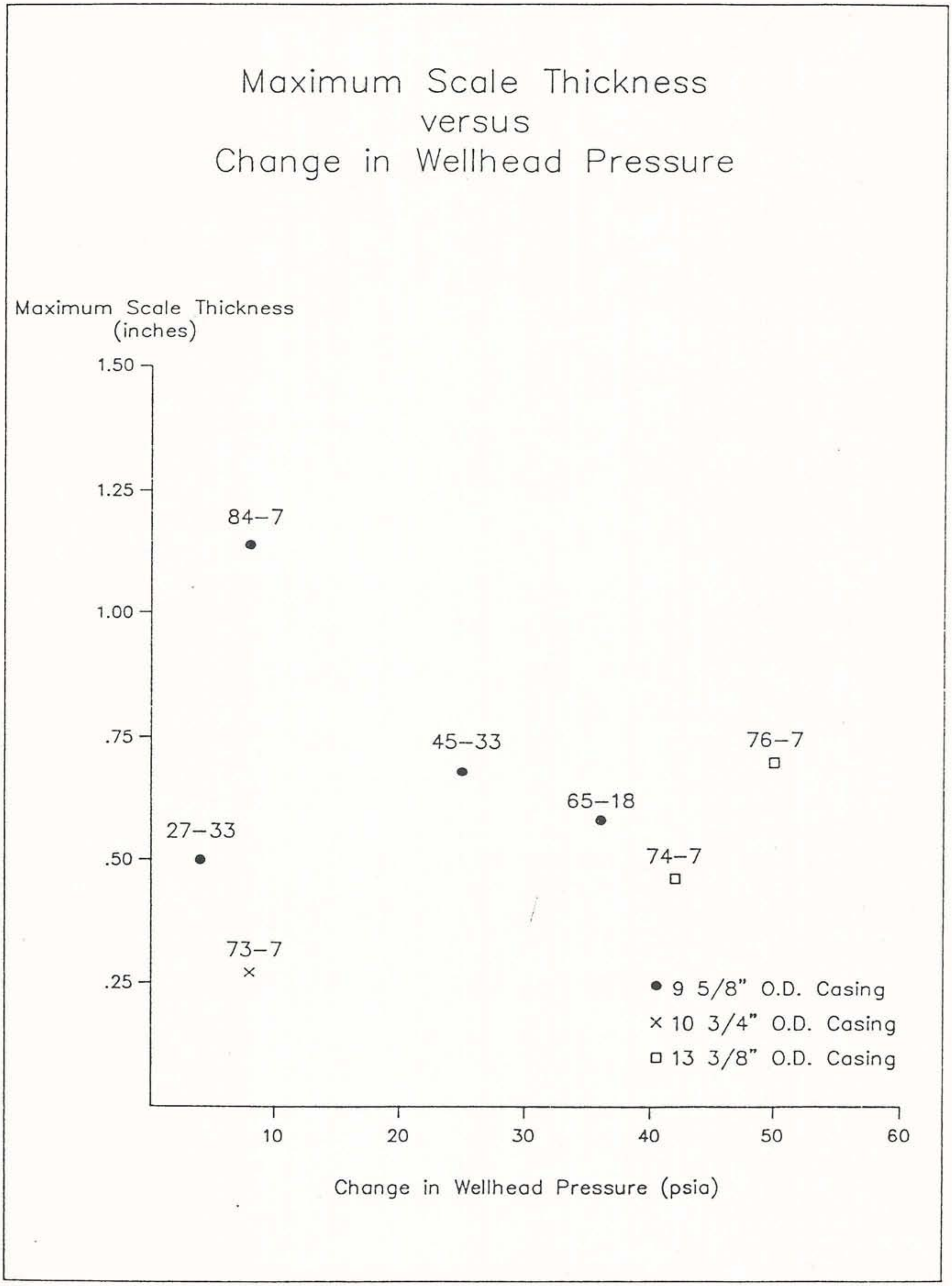

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Figure 10

The 13 3/8" casing cross section is only twice as large as the 9 5/8" cross section so some factor other than just cross sectional area is active but it is not yet understood.

Wells with both sizes of completions are present at Dixie Valley hence all of the figures have been constructed to discriminate between the different sizes. The average scaling rates have similar ranges for the 9 5/8" and 13 3/8" casings (Figure 11). This by itself indicates that the only reason the 13 3/8" wells will take longer to scale up is the larger cross sectional area. But this will only double the time between scale cleanouts. Possibly some, as yet undocumented, factor such as the scale becoming more average in thickness over the length of the scaled interval with time (and increased amounts of scale) will allow the 13 3/8" completions to flow several times as long as the 9 5/8" completions between scale cleanouts.

The rate of increase in the scaling rates with time (and increasing amounts of scale) is apparently different for the 9 5/8 and the 13 3/8" wells (Figure 12). However, the interpretation of Figure 12 is not straight foreward. For instance, if the scaling rate for the 9 5/8" wells is extrapolated the scaling rate will increase drastically for all the wells and they will essentially scale shut when only 150,000 to 200,000 cubic inches of scale has been deposited. What has probably happened is that the variation in scaling characteristics between the individual wells is so great that the trend is not real. These data do not allow us to accurately extrapolate the scaling rates as the wells become progressively scaled.

The depths at which the scale forms is also a production concern. There is 9 5/8" casing in wells 27-33, 45-33, 84-7, and 65-18 so it makes little difference (aside from wellhead pressure) if the scaled interval moves up or down the wellbore. The scaling characteristics should remain the same with the maximum scale thickness being the limiting factor. In wells 73-7, 76-7, and 74-7 the 10 3/4" or 13 3/8" casing is reduced to a 9 5/8" liner between depths of 3256' and 3776'. If the scaled interval moves down into this smaller casing the scaling characteristics will change and the time between cleanouts will be reduced substantially.

The present bottom of the scaled interval in wells 73-7 and 76-7 are 825'and 764' respectively above the reduction in casing size. It was previously noted that the flash point will move about 200' up or down the wellbore for each 10

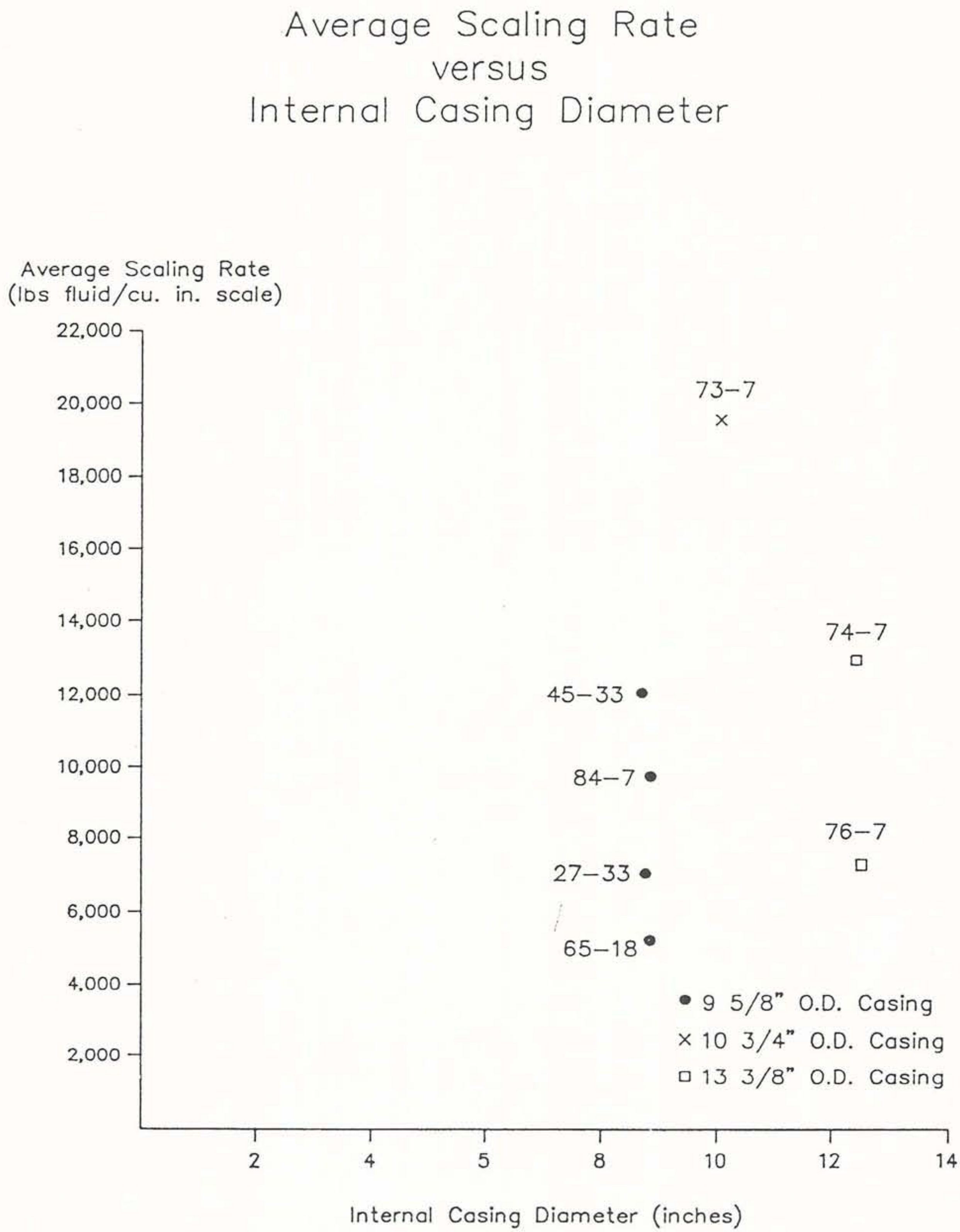

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Figure 11

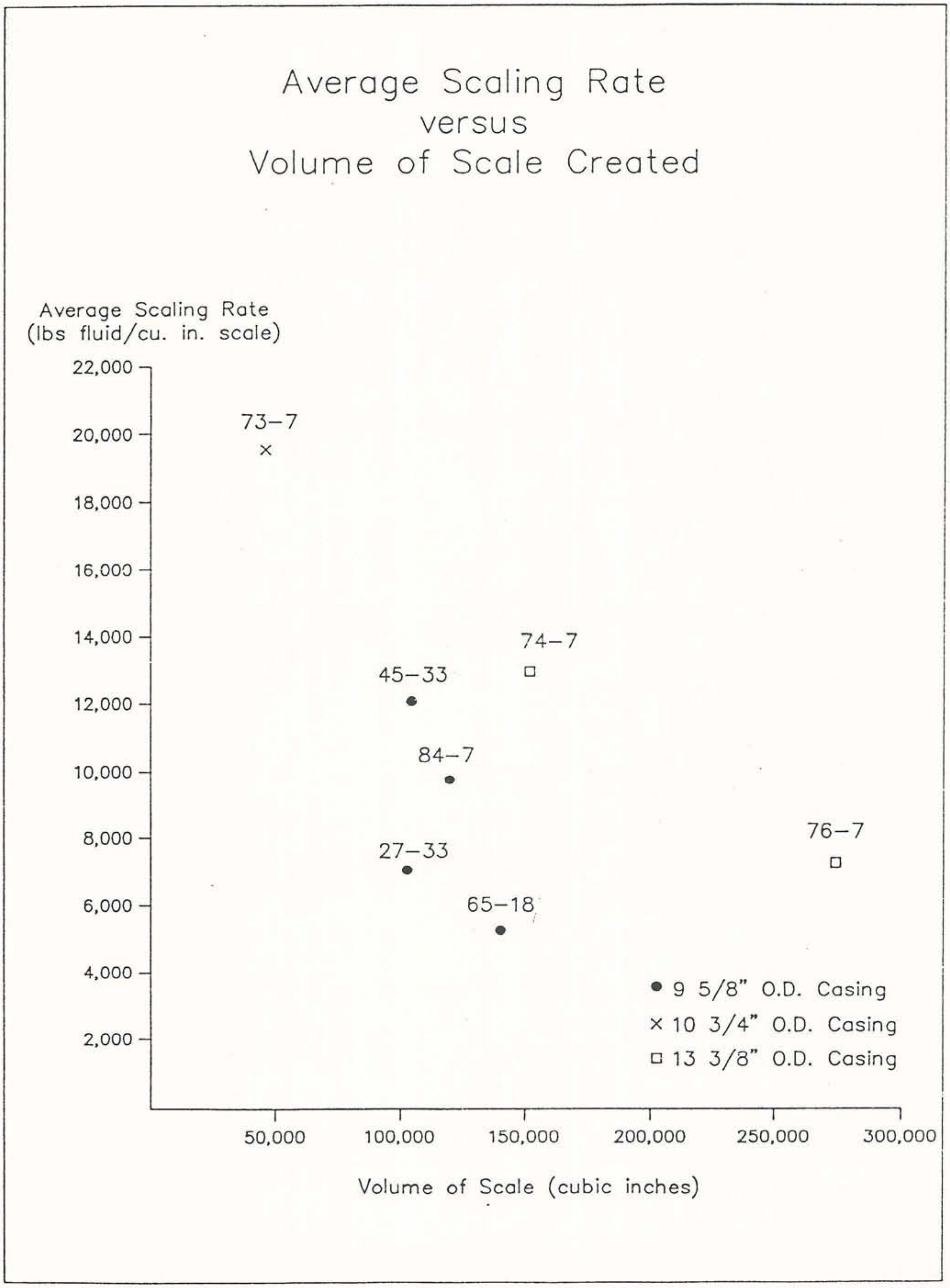

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Figure 12

pound change in wellhead pressure. As the wellhead pressure decreases, the flash point moves to a greater depth. A 40 pound wellhead pressure drop in wells 73-7 and 76-7 could lower the flash point into the 9 5/8" liner. It is unlikely that the scaled interval will move down this far in the near future. However, the scale in well 74-7 starts at the top of the 9 5/8" liner hanger. Any further downward movement of the scaled interval will substantially reduce the time between cleanouts.

In working with actual depths to the bottom and top of scaled intervals the calculated flash point depths, rather than the wellhead pressure changes, are used in the interpretation. These flash point depths have been corrected for the noncondensible gas content actually measured in each well. Figures 13 and 14 show the calculated final and initial flash point depths for the wells versus the measured depth to the bottom and top of the scaled intervals. There is good correlation between the final flash point depth and the depth of the bottom of the scaled interval.

The correlation between the initial flash point depth and the top of the scaled interval (Figure 14) is not very close. The calculated initial flash points are from 483 to 1041' deeper than the measured top of the scale. This reflects the extra time and distance it takes for the carbon dioxide gas to exsolve from the brine above the flash point and provides another estimate of the minimum scale length that can ever be expected. This estimated minimum scale length is in general agreement with that previously indicated from Figure 9.

The scaling rate for each well is a unique feature of the individual well and that by varying the wellhead pressure it is possible to lengthen the scaled interval and decrease the maximum scale thickness. However, the available data are not suitable for predicting scaling rates as the wells become progressively more scaled. Nor is it possible to predict the future distribution of scale as the wells become progressively scaled. This in part reflects the fact that none of the wells have been flowed to the point where they were severely scaled. The thickest scale yet measured is only 1.14".

ESTIMATED TIME INTERVALS BETWEEN SCALE CLEANOUTS

There is no unique solution to the question of how long can the individual wells go between scale cleanouts. This depends on how the wells are produced and what ultimate amount of restriction in flow rate and pressure is acceptable. This in turn gets into questions of how much

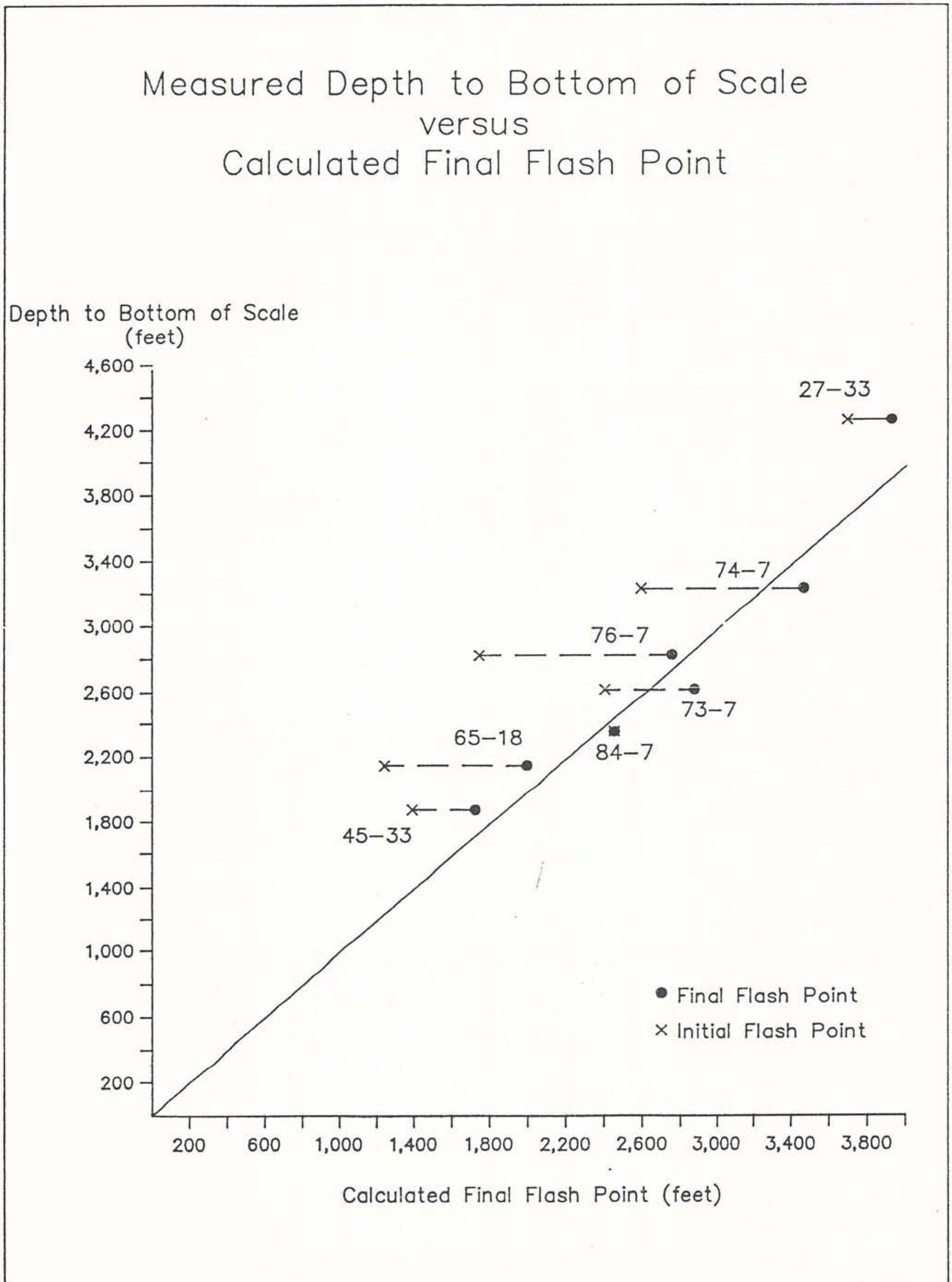

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Figure 13

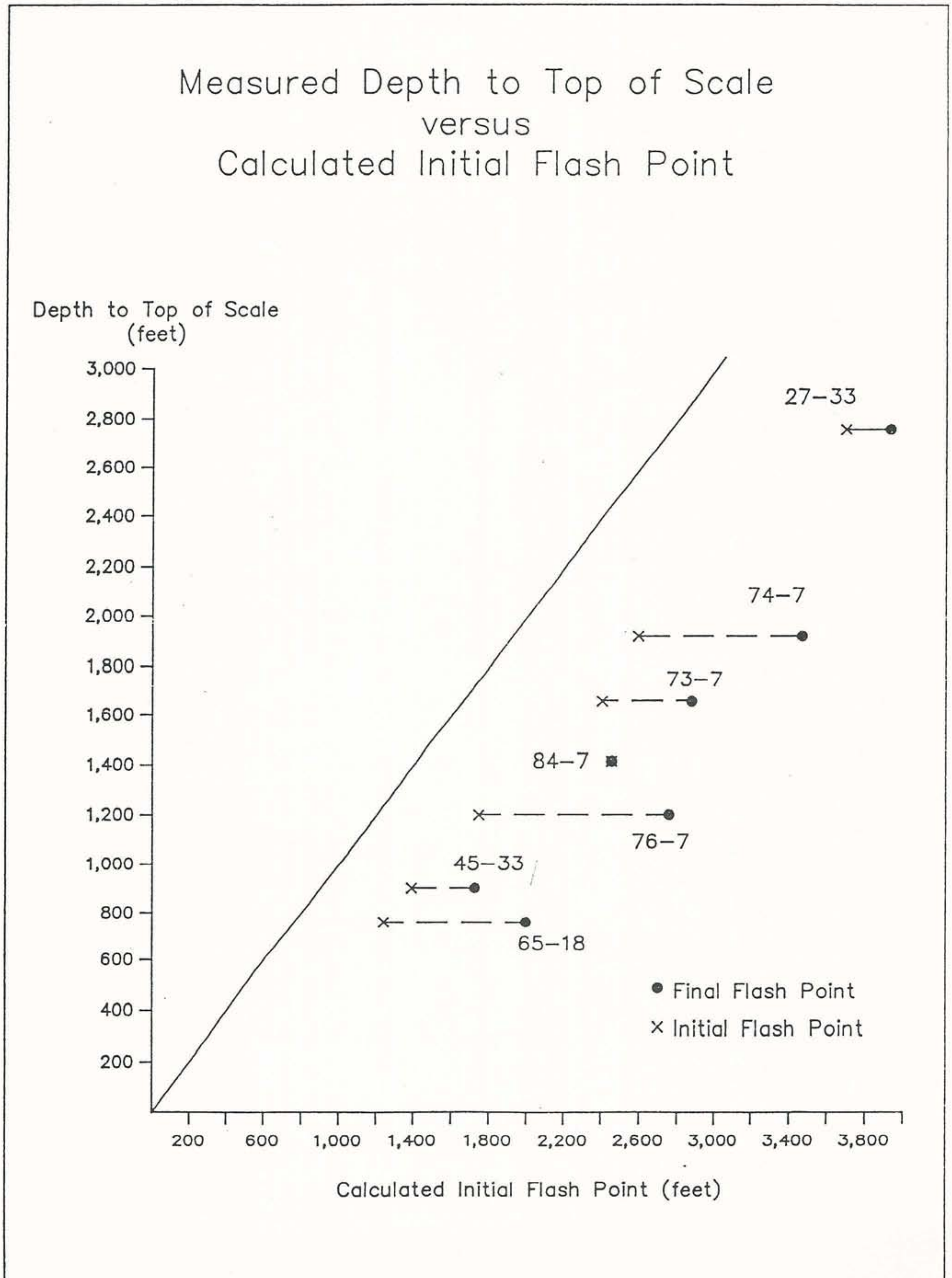

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Figure 14

excess well capacity is available so that the wells can be throttled back to raise the flash point and lengthen the scaled interval.

At this time the length of time between cleanouts can only be estimated by making the assumptions listed below:

1. The scaling rate remains constant and the length to thickness ratio of the scale does not appreciably change with increasing scale thickness. In reality, the scaling rate is expected to increase which will decrease the time between cleanouts. This may be offset by a change in the distribution of scale in which the average thickness increases throughout the scaled interval. This would slow down the growth of scale in the maximum thickness interval.

2. The scaled interval in a well does not migrate down into smaller casing with time. This is a factor which can be controlled to a certain extent in the short term. In the long term, as reservoir pressures decline with time, it may not be possible to prevent the downward scale migration into the smaller casing.

3. The wells are flowed in the same manner as they were during the 1986 flow testing. A major purpose of this report is to predict the amount of time between scale cleanouts. Consequently days and not production volumes are used to make the predictions. In this assumption there is no provision for throttling the wells back to lengthen the scaled interval and no provision is made for the declining flow rate as the well becomes progressively scaled (short term) and the reservoir pressure declines (long term).

4. A well that is between 65 percent and 70 percent scaled will no longer flow at acceptable wellhead pressure and will be cleaned out. This amount was chosen by analogy with a gate valve closing a well. Until the gate valve is 2/3 or 3/4 closed there is little impact on the wellhead parameters. To date at Dixie Valley the 84-7 wellhead parameters were not significantally impacted when the wellbore was 45 percent restricted by scale. Using a figure of 70 % in this analysis does not mean that Oxbow is committed to this figure. Under actual operating conditions 70 % might result in an unacceptable flow rate or wellhead pressure. At the present time what is unacceptable has not been defined.

5. No attempt is made to remove the scale on a continuing short term basis.

Well 74-7

Well 74-7 has the simplest scale profile (Figure 1). This profile shows basically a wedge from maximum thickness at the bottom to a point at the top of the scale. If the scale length remains constant and the wedge continues to grow thicker, then the following discussion may prove reasonably accurate.

This well has a maximum scale thickness of 0.46" after producing 1.97 billion pounds of fluid (Table 1). This thickness of scale reduced the open cross sectional area of the entire wellbore by 14% ; from 121.06 square inches to 103.78 square inches. A maximum scale thickness of 2.81" would reduce the cross sectional area by 70% to leave an open cross sectional area of 36.32 square inches. The 82 days of production have therefore blocked about 20 % of the assumed blockable cross section. Therefore a crude and optimistic estimate of the time between scale cleanouts would be 5 times 82 days or 410 days.

However, this does not take into account the fact that the same volume of scale in a progressively smaller wellbore will result in progressively higher percentages of blockage as the scale will be thicker, assuming the length of the scaled interval remains constant. Therefore it is more realistic in extrapolating the scaling rate to include a factor that takes into account the smaller available wellbore.

A simple incremental factor based on existing amounts of production and blockage is used. In the case of well 74-7 it is assumed that the next 1.97 billion pounds of fluid should produce a scale rind on the order of 14 % greater thickness than the original 0.46" as the cross sectional area of the well has already been reduced by 14 %. The third increment would produce a scale rind 14% thicker than the second increment and so forth. Extrapolating the increasing scale thickness with decreasing open wellbore radius in increments of 1.969 billion pounds of production indicates the well will be almost 70 % blocked after 4 increments or in 324 days. By then the well would have produced almost 8 billion pounds of fluid assuming no decline in flow rate. It is reasonable to expect that well 74-7 will flow at least 9 months between scale cleanouts if the scale remains in the 13 3/8" casing and there are no major changes in scaling characteristics.

This is in agreement with the yearly scale cleanouts for the 13 3/8" wells at Desert Peak and

Roosevelt. The 13 3/8" wells at Roosevelt are capable of producing in excess of 5 billion pounds of fluid between scale cleanouts. During the first year of operation at Desert Peak, the two 13-3/8" production wells produced slightly over 7 billion pounds before they were cleaned out.

Well 76-7

Well 76-7 had a maximum scale thickness of 0.70" after producing 1.997 billion pounds of fluid in 65 days. The scale reduced the open cross sectional area of the wellbore by 21 %; from 123.0 square inches to 97.0 square inches. Extrapolating scale buildup in the same incremental method that was used for well 74-7 indicates that after 3 increments of 1.997 billion pounds of production the well will be almost 70 % scaled shut. This would be after 195 days and almost 6 billion pounds of fluid.

There is every reason to expect well 76-7 will flow for six months between cleanouts if the scale is confined to the 13 3/8" casing. Well 76-7 will apparently require more frequent cleanouts than 74-7 even though both have 13 3/8" casing.

Well 45-33

Well 45-33 had a maximum scale thickness of 0.68" after producing 1.26 billion pounds in 60 days. The scale reduced the open cross sectional area of the wellbore by 29 %; from 59.19 square inches to 42.08 square inches. If another 1.26 billion pounds of fluid were produced the wellbore would be approximately 59 % scaled shut so it is likely that well 45-33 will need to be cleaned out once every 4 months or after 2.5 billion pounds of production.

Well 65-18

Well 65-18 had a maximum scale thickness of 0.58" after producing 737 million pounds of fluid in 54 days. The scale reduced the open cross sectional area of the wellbore by 25%; from 61.31 square inches to 46.26 square inches. If two more increments of 737 million pounds of production were flowed through the well, the wellbore would be about 75 % scaled shut. Therefore this well might produce for 4 to 5 months or about 2 billion pounds of fluid between scale cleanouts if it were to be used as a producer. However, the relatively low wellhead pressure of this well would probably decline to unacceptable levels after 3 to 4 months, rendering it unsuitable for supplying the power plant. The main reason that this well would last longer than 45-33 between cleanouts is that it produces at a lower flow rate.

Well 84-7

Well 84-7 had a maximum scale thickness of 1.14" after producing 1.17 billion pounds of fluid in 75 days. The scale reduced the open cross sectional area of the wellbore by 45%; from 61.31 square inches to 33.75 square inches. If this well produced another 1.17 billion pounds of fluid, the wellbore would be more than 70% scaled shut. Well 84-7 is scheduled for a workover which is expected to improve its maximum flow rate by about 30%. Therefore there is no point in making a projection of time intervals between cleanouts as this is in large part dependent on the flow rate. In its current condition, 84-7 should flow for about 3 to 4 months between cleanouts. Increasing the flow rate, assuming all other factors remain constant, will decrease the time interval between cleanouts. Until more information becomes available an estimate of 3 months between cleanouts seems conservative.

Well 73-7

The scale information from well 73-7 is not deemed adequate to make a projection of times between cleanouts based on scale thickness. Well 73-7 is completed with 10 3/4" casing and is expected to be intermediate between the 9 5/8" and the 13 3/8" completions in scale cleanout time intervals. This would mean that scale cleanouts will probably be needed every 5 to 7 months.

WELL 27-33

Since well 27-33 has been reworked, no scale data are available. It is expected that 27-33 should flow for 3 to 4 months between cleanouts.

These are admittedly crude estimates and perhaps other more rigorous methodologies would provide more precision. There are many unknowns regarding future scaling characteristics and variables regarding production strategies that have not yet been worked out. Putting additional work into these predictions is not now warranted.